Tariff Information Paper

nationalgrid

Draft TNUoS tariffs for 2015/16

This information paper provides Draft Transmission Network Use of System (TNUoS) tariffs for 2015/16. These tariffs apply to generators and suppliers.

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V1.0

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Any Questions?

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1 Executive Summary

The 2015/16 TNUoS tariffs, published before the end of January 2015, will be used to derive TNUoS charges for 2015/16. This document contains draft 2015/16 Transmission Network Use of System (TNUoS) tariffs, updating the previous forecast in October.

In accordance with EU Regulation 838/2010, which caps annual average generator charges to €2.5/MWh and CUSC Modification Proposal CMP224, the revenue to be recovered from generation is restricted to £613m. This is 23.1% of total revenues, which is 0.2% lower than the October forecast as a result of an increase in forecast revenues.

The forecast of total transmission revenue recovered from TNUoS charges has increased from £2,633m to £2,655m. There has been movement in all TO revenues, most significantly additional revenue to fund the Caithness - Moray Strategic Wider Works announced by Ofgem on 16 December. This is offset to a large degree by reductions in other TO revenues. Final transmission owner revenues are not submitted to us until late January so are subject to change. However, at this stage we are not expecting any significant changes.

The data that has been used to calculate the locational element of tariffs will remain unchanged for the final tariffs. The chargeable generation background reflects our best view of the generators that will be liable for TNUoS charges in 2015/16, this feeds into the residual element of tariffs and could be subject to change between now and setting final tariffs. Chargeable demand remains unchanged from the October forecast.

2 Introduction

2.1 Background

National Grid sets Transmission Network Use of System (TNUoS) tariffs for generators and suppliers. These tariffs serve two purposes: to reflect the transmission cost of connecting in different parts of the country and to recover the total allowed revenues of onshore and offshore transmission owners.

To reflect the cost of connecting in different parts of the network, we use a model of power flows on the transmission system to determine the locational component of TNUoS tariffs. This model considers the impact that increases in generation or demand have on power flows at times of peak demand. To calculate flows on the network, information about the generation and demand connected is used in conjunction with the electrical characteristics of the transmission system.

The charging model includes information about the cost of investing in transmission circuits based on different types of generic construction, e.g. voltage, cable / overhead line, and costs incurred in different TO regions. Onshore, these costs are based on 'standard' conditions and are intended to be forward looking. This means that they reflect the cost of replacing assets at current rather than historical cost so they do not necessarily reflect the actual cost of investment to connect a specific generator or demand site. However, for offshore networks, project specific costs are taken into account since these costs vary significantly from one project to another.

The locational component of TNUoS tariffs does not recover the revenue that onshore and offshore transmission owners are allowed in their price controls or in the correct proportions between Generation and Demand. Therefore, separate, non-locational "residual" tariff elements are included in the generation and demand tariffs. The residuals are set to ensure that the correct amount of revenue is recovered and in the correct proportions.

The locational and residual tariff elements are combined into a zonal tariff, referred to as the wider zonal generation tariff or demand tariff, as appropriate. For generation customers, local tariffs are also calculated. These reflect the cost associated with the transmission substation they connect to and, where a generator is not connected to the Main Interconnected Transmission System (MITS), the cost and use of circuits between their connection and the MITS ('local charges'). These charges are therefore locational and specific to individual generators.

We produce an initial view of tariffs fourteen months before the charging year starts. Over time the data used in the model is updated until the tariffs are finalised two months ahead of the charging year. The degree of uncertainty in the forecasts reduces as we get closer to publishing tariffs at the end of January. Scenarios are provided in some cases to show the effect of uncertainties that could have a significant impact on tariffs.

3 Tariff Summary

This section shows draft generation and demand TNUoS tariffs for 2015/16. Information on how these tariffs were calculated and why they have changed from the forecast published in October can be found in later sections.

23.1% of revenue will be recovered from generation and 76.9% from demand.

3.1 Generation Tariffs 2015/16

Table 1 – Generation Wider Tariffs

2015/16 Wider Generation Tariffs		
Zone	**Zone Name**	**£/kW**
1	North Scotland	25.50
2	East Aberdeenshire	21.04
3	Western Highlands	23.41
4	Skye and Lochalsh	28.82
5	Eastern Grampian and Tayside	22.17
6	Central Grampian	21.60
7	Argyll	22.84
8	The Trossachs	17.98
9	Stirlingshire and Fife	17.11
10	South West Scotland	15.78
11	Lothian and Borders	13.32
12	Solway and Cheviot	11.57
13	North East England	8.55
14	North Lancs and The Lakes	7.68
15	South Lancs, Yorks and Humber	6.21
16	North Midlands and North Wales	4.84
17	South Lincs and North Norfolk	2.93
18	Mid Wales and The Midlands	2.04
19	Anglesey and Snowdon	7.64
20	Pembrokeshire	5.89
21	South Wales	3.26
22	Cotswold	0.16
23	Central London	-5.26
24	Essex and Kent	-0.79
25	Oxfordshire, Surrey and Sussex	-2.60
26	Somerset and Wessex	-3.99
27	West Devon and Cornwall	-5.85
Small generators discount		9.85

Table 2 – Local Substation Tariffs

Substation Rating	Connection Type	Local Substation Tariff (£/kW)		
		132kV	275kV	400kV
<1320 MW	No redundancy	0.179739	0.102822	0.074085
<1320 MW	Redundancy	0.395951	0.244977	0.178168
>=1320 MW	No redundancy	-	0.322393	0.233156
>=1320 MW	Redundancy	-	0.529287	0.386336

Table 3 – Local Circuit Tariffs

Substation Name	(£/kW)	Substation Name	(£/kW)	Substation Name	(£/kW)
Achruach	3.84	Dersalloch	1.59	Killingholme	0.27
Afton	2.08	Didcot	0.23	Kilmorack	0.18
Aigas	0.59	Dinorwig	2.15	Langage	0.59
An Suidhe	2.73	Dumnaglass	3.24	Lochay	0.33
Arecleoch	0.29	Dunlaw Extension	1.31	Luichart	1.02
Baglan Bay	0.66	Edinbane	6.13	Marchwood	0.34
Black Law	0.90	Fallago	0.97	Mark Hill	-0.78
Blacklaw Extension	1.97	Farr Windfarm	2.14	Millennium Wind	1.46
Bodelwyddan	0.10	Ffestiniogg	0.23	Mossford	3.55
Brochloch	1.92	Finlarig	0.29	Nant	-1.10
Carraig Gheal	3.94	Foyers	0.68	Neilston	2.14
Carrington	0.00	Glendoe	1.65	Rocksavage	0.02
Clyde (North)	0.10	Glenmoriston	1.18	Saltend	0.30
Clyde (South)	0.11	Gordonbush	1.16	South Humber Bank	0.75
Corriegarth	2.27	Griffin Wind	1.67	Spalding	0.27
Corriemoillie	2.46	Hadyard Hill	2.48	Strathy Wind	2.64
Coryton	0.05	Harestanes	4.78	Whitelee	0.10
Cruachan	1.59	Hartlepool	0.53	Whitelee Extension	0.26
Crystal Rig	0.37	Hedon	0.18		
Culligran	1.55	Invergarry	1.27		
Deanie	2.55	Kilbraur	1.03		

Table 4 – Offshore Local Tariffs

Offshore Generator	Tariff Component (£/kW)		
	Substation	Circuit	ETUoS
Robin Rigg East	-0.41	27.44	8.50
Robin Rigg West	-0.41	27.44	8.50
Gunfleet Sands 1 & 2	15.68	14.39	2.69
Barrow	7.24	37.89	0.94
Ormonde	22.39	41.71	0.33
Walney 1	19.32	38.49	0.00
Walney 2	19.18	38.82	0.00
Sheringham Shoal	21.63	25.37	0.55
Greater Gabbard	13.58	31.20	0.00
London Array	9.21	31.38	0.00
Lincs	13.54	54.27	0.00

3.2 Demand Tariffs 2015/16

Half Hour metered zonal tariffs (£/kW) and Non-Half Hour metered zonal tariffs (p/kWh)

Table 5 – Demand Tariffs

Zone	Zone Name	HH Demand Tariff (£/kW)	NHH Demand Tariff (p/kWh)
1	Northern Scotland	22.53	3.25
2	Southern Scotland	25.85	3.43
3	Northern	31.68	4.16
4	North West	34.74	4.74
5	Yorkshire	35.35	5.05
6	N Wales & Mersey	34.68	5.52
7	East Midlands	38.12	5.11
8	Midlands	38.69	5.35
9	Eastern	40.23	5.41
10	South Wales	36.67	5.11
11	South East	42.80	5.68
12	London	45.30	5.89
13	Southern	43.85	5.96
14	South Western	43.04	5.68

4 Updates to the 2015/16 Charging Model

Since the October forecast of tariffs, updates have been made to the contracted generation background, generation charging base, total revenue and RPI indexed parameters (expansion constant, local tariffs). There have also been minor changes to the transport model demand data following an update to embedded generation.

4.1 Changes influencing the locational element of tariffs

4.1.1 Generation

Draft tariffs have been calculated using contracted generation on 31 October 2014 in the transport model and our best view of chargeable generation for 2015/16 in the tariff model. The difference between contracted generation and chargeable generation reflects our forecast of closures and delays to new power stations.

The most significant changes to contracted generation since the October forecast are increases of 910MW in zone 15 and a reduction of 500MW from the east side of zone 18.

Table 6 shows contracted and modelled Generation (Transmission Entry Capacity or TEC) in this forecast compared to previous forecasts and 2014/15. Changes in contracted TEC since the October forecast can be found in Appendix A.

Table 6 - Contracted and Modelled TEC

(GW)	2014/15	2015/16 May forecast	2015/16 July forecast	2015/16 October forecast	2015/16 Draft Tariffs
Contracted TEC	77.2	80.3	78.8	78.7	78.7
Modelled TEC	77.2	79.5	77.9	78.4	78.7

4.1.2 Demand

The locational element of tariffs is based upon: week 24 demand forecast data provided by the Distribution Network Operators (DNO) under the Grid Code, forecasts of demand at directly connected demand sites such as steelworks and railways and some embedded generation. The DNO demand data used in this forecast is unchanged from that used in previous forecasts and will not change before charges are finalised in January 2015. However, embedded generation and directly connected demand have been updated since October resulting in a small change in embedded generation for 2015/16 (embedded generation reduces demand).

Table 7 - Transport Model Demand (GW)

(GW)	2014/15	2015/16 May forecast	2015/16 July forecast	2015/16 October forecast	2015/16 Draft Tariffs
Transport Model Demand	56.6	55.6	55.7	55.7	55.7

4.1.3 Network Model Changes

Minor amendments have been made to the network model data following an audit of information received from transmission owners. These changes have only affected local tariffs.

4.2 Changes influencing the residual element of tariffs

4.2.1 Allowed Revenues

National Grid recovers revenue on behalf of all onshore and offshore Transmission Owners (TOs) in Great Britain. Table 8 shows the forecast 2015/16 revenues that have been used in this tariff forecast. Earlier forecasts and the final revenue upon which 2014/15 tariffs were set are also included for comparison.

The revenues of onshore TOs are subject to RIIO price controls set by Ofgem at periodic price reviews. RIIO stands for Revenue = Incentives + Innovation + Outputs. Revenue is initially set at a price review and then adjusted during the price control period depending on performance against incentives, innovation and outputs delivered. Revenue adjustments are generally lagged by two years, so allowed revenues in 2015/16 are adjusted to reflect outputs and performance in 2013/14.

National Grid

Ofgem's determinations in November on the adjustment to base revenues, Stakeholder Engagement Award and Environmental Discretionary Award have been taken into account. The Treasury's November 2014 forecast for inflation which is used to inflate allowances to 2015/16 prices has also been taken into account. As GB system operator, National Grid receives revenue from Scottish customers and makes payments to Scottish Transmission Owners for connection assets and terminations. Timing differences between Scottish income and payments are included in allowed revenue the following year and have been forecast at £3.4m. Changes in this forecast when tariffs are finalised are expected to be less than +/- £2m.

Scottish Power Transmission (SPT)

We have used SPT's forecast of 2015/16 revenue submitted at the end of October under the System Operator-Transmission Owner Code. SPT's forecast included their estimate of Ofgem's determinations expected in November. Where there are differences then these will be reflected in their submission at the end of January which is used to finalise tariffs. However, the variation is expected to be of the order of a few million pounds

SHE Transmission (SHET)

We have used SHET's forecast of 2015/16 revenue submitted at the end of October under the System Operator-Transmission Owner Code. SHET's forecast included their estimate of Ofgem's determinations, including funding for the Caithness-Moray project from 2015/16. Ofgem have since confirmed the Caithness-Moray project will be funded from 2015/16 and expect to determine the adjustment to SHE Transmission's revenue allowances in January, in time for SHET's submission at the end of January which is used to finalise tariffs. We anticipate the variation from this forecast will be of the order of +/- £10m.

Offshore Transmission Owners

Offshore Transmission Owners (OFTO) revenues are determined by Ofgem in a competitive tender process. The revenue is confirmed when the network is transferred from the developer to the appointed OFTO. Prior to this there is uncertainty as to the value of the revenue and when it will start. Therefore, whilst the revenues for existing OFTOs can generally be predicted by indexing previous year revenues, the revenue for new OFTOs has to be forecast.

Existing OFTOs include Barrow, Gunfleet, Walney 1 & 2, Robin Rigg, Sheringham Shoal, Ormonde, London Array, Greater Gabbard and Lincs. Gwynt y Môr, Thanet, and West of Duddon Sands are expected to transfer during the remainder of 2014/15. Humber Gateway and Westermost Rough are expected to transfer in 2015/16 but later in the year compared to the October forecast leading to a reduction in OFTO revenue.

Network Innovation Competition

Ofgem has awarded £18.8m of funding under the electricity transmission Network Innovation Competition Fund. National Grid will collect this in 2015/16 on behalf of itself and the other successful bidders. The electricity distribution equivalent of this fund will not require funding from TNUoS tariffs until 2016/17 so is not included in this forecast.

Table 8 – Allowed Revenues

£m Nominal	2014/15 TNUoS Revenue	2015/16 TNUoS Revenue				
	Jan 2014 Final	Jan 2014 Initial View	April 2014 Update	July 2014 Update	Oct 2014 Update	Dec 2014 Draft
National Grid						
Price controlled revenue	*1,761.9*	*1,855.6*	*1,851.6*	*1,805.9*	*1,810.9*	*1,783.1*
Less income from connections	*47.0*	*47.0*	*47.0*	*47.0*	*47.0*	*48.3*
Income from TNUoS	**1,714.9**	**1,808.7**	**1,804.6**	**1,759.0**	**1,763.9**	**1,734.8**
Scottish Power Transmission						
Price controlled revenue	*323.0*	*342.3*	*341.6*	*344.7*	*322.8*	*310.5*
Less income from connections	*10.8*	*9.8*	*9.8*	*11.5*	*10.8*	*11.1*
Income from TNUoS	**312.2**	**332.5**	**331.8**	**333.2**	**312.0**	**299.4**
SHE Transmission						
Price controlled revenue	*217.4*	*219.3*	*218.7*	*229.7*	*270.3*	*362.7*
Less income from connections	*3.5*	*3.6*	*3.5*	*3.6*	*3.6*	*10.9*
Income from TNUoS	**214.0**	**215.7**	**215.2**	**226.2**	**266.8**	**351.9**
Offshore	**218.4**	**276.4**	**276.4**	**277.3**	**274.1**	**249.9**
Network Innovation Competition	**17.8**	**16.7**	**16.6**	**16.7**	**16.7**	**18.8**
Total to Collect from TNUoS	**2,477.3**	**2,650.0**	**2,644.7**	**2,612.3**	**2,633.4**	**2,654.7**

4.2.2 Generation: Demand Split

The annual average generator tariff is limited to €2.5/MWh. This limit has been reduced to €2.34/MWh to incorporate a risk margin for forecasting error. The amount of money to be recovered from generation is calculated as €2.34/MWh multiplied by 319.6TWh of forecast generation which gives €747.9m

Dividing by an exchange rate of €1.22/£ results in £613m of revenue to be recovered from generation. Since the limit, forecast generation and exchange rate are unlikely to change; the money to be recovered from generators is now fixed for 2015/16 regardless of any change in total revenue.

The proportion of revenue recovered from generation is generation revenue divided by total revenue. Hence, whilst generation revenue is fixed at £613m, changes in total revenue will change the proportion of revenue recovered through generation charges.

Table 9 shows the parameters used to calculate the revenue recovered from generation and demand in 2014/15 and 2015/16.

4.2.3 Generation Residuals

Revenue Recovered from Generators

The revenue to be collected from generators is fixed at £613m. Onshore local, offshore local and locational charges recover a significant proportion of this and what remains is recovered through the residual.

Onshore Local Charges

In this forecast onshore local substation and onshore local circuit charges equate to £34m, this number is dependent upon chargeable generation and remains relatively stable.

Offshore Local Charges

Offshore local charges are forecast to be £189m. Of this £142m is certain and £49m is dependent upon the asset transfer dates of Gwynt Y Mor, West of Duddon Sands, Westermost Rough and Humber Gateway. On average, local offshore charges account for 75% of the OFTOs revenues. The potential variability of OFTO revenues are detailed in Section 7.1.1.

Locational Generation Wider Charges

The locational element of generation charges is forecast to be £49m. Locational tariffs are now fixed but the £m charge is dependent upon the chargeable generation base.

Calculating the Generation Residual

For this forecast, the revenue to be recovered through the generator residual tariff is:

£613m - £34m - £189m - £49m = £341m.

The generation residual tariff is calculated by sharing this revenue across the generation base:

£341m / 71.6GW = £4.77/kW

Table 10 shows a comparison of 2014/15 and 2015/16 generation residual parameters.

4.2.4 Demand Residuals

Revenue Recovered from Demand

Revenue collected from demand customers is calculated as total TNUoS revenue less revenue recovered from generation customers. Since revenue recovered from generation is now fixed, all further changes to total transmission revenues will be recovered through demand charges. In this forecast, the revenue recovered from demand customers equates to:

£2,655m - £613m = £2,042m

Locational Demand Charges

The locational element of demand charges is forecast to be £163m. Locational tariffs are now fixed but the £m charge is dependent upon the chargeable demand base.

Calculating the Demand Residual Charges

For this forecast, the revenue to be recovered through the demand residual tariff is:

£2,041m - £163m = £1,878m

Calculating the Demand Residual tariff

The demand residual tariff is calculated by sharing this revenue across the demand charging base:

£1,878m / 54.2GW = £34.66kW.

Table 10 shows a comparison of 2014/15 and 2015/16 demand residual parameters.

Table 9 - G/D Split Calculation

	2014/15	2015/16
E (TWh)	322.0	319.6
L (€/MWh)	2.50	2.34
R (£m)	2,477.3	2,654.7
X (€/£)	1.20	1.22
G	0.27	0.231
D	0.73	0.769
G.D (£m)	668.9	613
R.D (£m)	1808.4	2041.7

Table 10 - Residual Calculation

		2014/15	2015/16
R_G (£/kW)	Generator residual tariff	5.81	4.76
R_D (£/kW)	Demand residual tariff	30.05	34.66
G (%)	Proportion of revenue recovered from generation	0.270	0.231
D (%)	Proportion of revenue recovered from demand	0.730	0.769
R (£m)	Total TNUoS revenue	2,477.3	2,654.7
Z_G (£m)	Revenue recovered from the locational element of generator tariffs	54.2	49.0
Z_D (£m)	Revenue recovered from the locational element of demand tariffs	146.5	163.1
O (£m)	Revenue recovered from offshore local tariffs	160.0	188.9
L_G (£m)	Revenue recovered from onshore local substation tariffs	18.5	20.1
S_G (£m)	Revenue recovered from onshore local circuit tariffs	12.2	14.3
B_G (GW)	Generator charging base	73.0	71.6
B_D (GW)	Demand charging base	55.3	54.2

4.3 Charging bases for 2015/16

Generation

The generation base for 2015/16 takes generation from the transport model (see Section 4.1.1) less;

- Interconnectors;
- An adjustment taking into account generators in negative zones who do not always generate up to TEC;
- Forecast changes to chargeable generation that are not included in the TEC register of 31 October, e.g. station closures, delayed works, advanced works

Demand

The demand forecast has not changed from that in the October forecast.

The peak demand forecast is 54.2GW which reflects the recent trend of reduced demand, increased embedded generation, as well as demand side response and Triad avoidance.

The distribution of peak demand reflects actual demand distribution between zones over the last three years; taking into account changes in embedded generation levels, Triad avoidance and closure of large demand sites.

The forecast for Non-Half Hour (NHH) metered demand, i.e. the chargeable energy between 4pm and 7pm each day, is 28.35TWh. This forecast also reflects a trend towards lower NHH demand in recent years, which included both colder and warmer than average winters.

It should be noted that actual peak demand (and the timing of the Triads in any given year) depends on a number of factors, including prevailing weather, and the behaviour of embedded generation, commercial and industrial demand.

Adjustments for Interconnectors

When determining the flows on the transmission system at peak demand, the interconnectors are included within the transport model. However, since interconnectors are not liable for generation or demand TNUoS charges, they are not included in the generation or demand charging bases. Table 11 shows Interconnectors in the transport model and charging base, which have not changed since the October forecast.

Table 11 – Interconnectors

Interconnector	Zone	Transport Model (Generation MW)	Charging Base (Generation MW)
French - Sellindge 400kV	24	2000	0
Britned - Grain 400kV	24	1200	0
East West - Deesside 400kV	16	500	0
Moyle - Auchencrosh 275kV	10	295	0

4.4 Expansion Constant

The expansion constant has been updated from the October forecast due to a reduction in forecast RPI from 2.6% to 2.4%. The Expansion Constant is now **£13.21255525/MWkm**. The expansion factor is calculated using a May-October average RPI. The average May – October index is 2.413%. The expansion constant will not change between this forecast and the final tariffs published in January.

5 Forecast 2015/16 Generation Tariffs

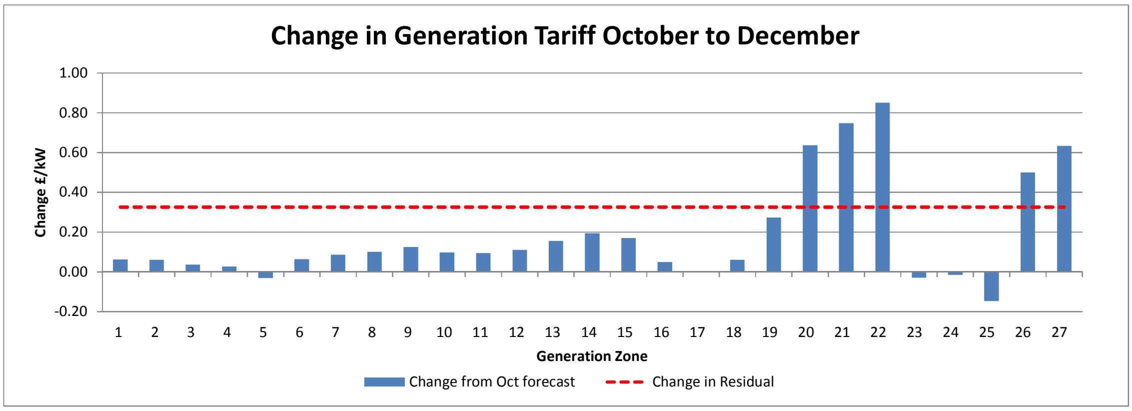
The following section provides details of the forecast wider and local generation tariffs for 2015/16.

Table 12 shows the forecast generation zonal TNUoS tariffs for 2015/16. Changes from the 2014/15 tariffs and October forecast are also shown for comparison purposes. Figure 1 shows the change from the October forecast graphically.

Table 12 - Wider Generation Charges

Wider Generation Tariffs (£/kW)				
Zone	**Zone Name**	**2015/16**	**Change from 2014/15 tariff**	**Change from Oct forecast**
1	North Scotland	25.50	-2.18	0.06
2	East Aberdeenshire	21.04	-1.93	0.06
3	Western Highlands	23.41	-4.95	0.04
4	Skye and Lochalsh	28.82	-4.97	0.03
5	Eastern Grampian and Tayside	22.17	-1.86	-0.03
6	Central Grampian	21.60	-0.38	0.06
7	Argyll	22.84	1.99	0.09
8	The Trossachs	17.98	-0.44	0.10
9	Stirlingshire and Fife	17.11	-0.91	0.12
10	South West Scotland	15.78	-0.68	0.10
11	Lothian and Borders	13.32	-0.86	0.09
12	Solway and Cheviot	11.57	-1.15	0.11
13	North East England	8.55	-1.32	0.16
14	North Lancs and The Lakes	7.68	-1.47	0.20
15	South Lancs, Yorks and Humber	6.21	-1.40	0.17
16	North Midlands and North Wales	4.84	-1.32	0.05
17	South Lincs and North Norfolk	2.93	-1.72	0.00
18	Mid Wales and The Midlands	2.04	-1.51	0.06
19	Anglesey and Snowdon	7.64	-0.94	0.27
20	Pembrokeshire	5.89	-0.67	0.64
21	South Wales	3.26	-0.52	0.75
22	Cotswold	0.16	-0.59	0.85
23	Central London	-5.26	-1.48	-0.03
24	Essex and Kent	-0.79	-2.23	-0.01
25	Oxfordshire, Surrey and Sussex	-2.60	-1.77	-0.15
26	Somerset and Wessex	-3.99	-1.29	0.50
27	West Devon and Cornwall	-5.85	-1.15	0.63

Figure 1 - Generation Tariff Changes



Residual Tariff

Due to the cap on average annual generation charges, once the exchange rate and generation (TWh) are fixed, the revenue recovered by generation is fixed too. The generation revenue of £613m remains the same in December as it was in October (allowing for rounding) and will remain the same for final tariffs. However, the revenue recovered by the generator residual tariff is dependent upon the local and locational charges, which are subtracted from total generator revenue to calculate the residual tariff.

The residual tariff has increased from £4.43/kW to £4.76/kW since the last forecast in October. Of this £0.33/kW increase, £0.22/kW is as a result of a decrease in the amount of revenue expected to be recovered from offshore generators. £0.12/kW of the increase is as a result of a reduction in the generation charging base i.e. fewer MW amongst which to collect the revenue. The reduction in the charging base is due to more forecast closures and delays to schemes.

Locational Tariff

The increase in generation in the south (approximately 400MW overall) causes a reduction in north to south flows which reduces tariffs in the north and increases tariffs in the South.

The reduction in generation in the south east also increases west to east flows, increasing tariffs in western zones 20,21, 22, 26, 27 (South Wales and Cornwall) and reducing tariffs in eastern zones 23, 24 and 25 (London, Essex, Kent).

5.1 Onshore local substation tariffs

Local substation tariffs (Table 2 in Section 3) are lower than the October forecast due to the RPI rate used to inflate tariffs dropping from 2.6% to 2.4%. This RPI index is now fixed and will be the same for the final tariffs.

5.2 Offshore local generation tariffs

The local offshore tariffs (Table 4, Section 3) are lower than the October forecast due to the RPI rate used to inflate tariffs dropping from 2.6% to 2.4%. This RPI index is now fixed and will be the same for the final tariffs.

5.3 Discount for Small Generation

The discount for small generation, which is equal to 25% of the combined generation and demand residuals, has increased to £9.85/kW, due to increases in both generation and demand residuals.

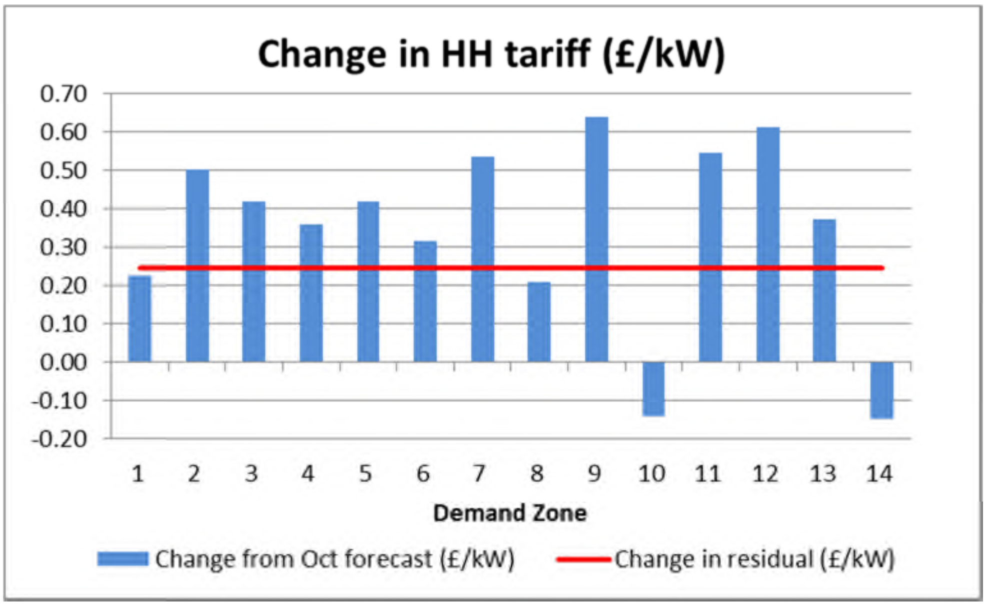
6 Forecast 2015/16 Demand Tariffs

Table 13 shows the 2015/16 Half-Hour (HH) demand tariffs. Changes from 2014/15 and the October forecast are shown for comparison. Figure 2 shows the change from the October forecast graphically.

Table 13 – HH Demand Tariffs

Zone	Zone Name	2015/16 (£/kW)	Change from 2014/15 (£/kW)	Change from Oct forecast (£/kW)
1	Northern Scotland	22.53	6.36	0.23
2	Southern Scotland	25.85	4.61	0.50
3	Northern	31.68	4.74	0.42
4	North West	34.74	5.10	0.36
5	Yorkshire	35.35	5.10	0.42
6	N Wales & Mersey	34.68	4.96	0.32
7	East Midlands	38.12	5.02	0.53
8	Midlands	38.69	4.91	0.21
9	Eastern	40.23	5.61	0.64
10	South Wales	36.67	4.35	-0.14
11	South East	42.80	5.14	0.55
12	London	45.30	6.75	0.61
13	Southern	43.85	5.06	0.37
14	South Western	43.04	4.34	-0.15

Figure 2 – HH Demand Tariff Changes



Residual Tariff

The residual element of HH demand tariffs has increased by £34.41/kW to £34.65/kW. The majority of this increase is due to the £22m increase in revenue recovered from demand customers.

Locational Tariff

The increase in contracted generation in the south reduces north to south flows and hence increases demand tariffs in the north. The decrease in generation in zone 9 increases west to east flows. The tariffs in South Wales, Midlands, Somerset, Devon and Cornwall (zones 8,10,14) decrease and those in Norfolk, Suffolk, Kent Essex, Surrey, Sussex (zones 7,9,11,12,13) increase.

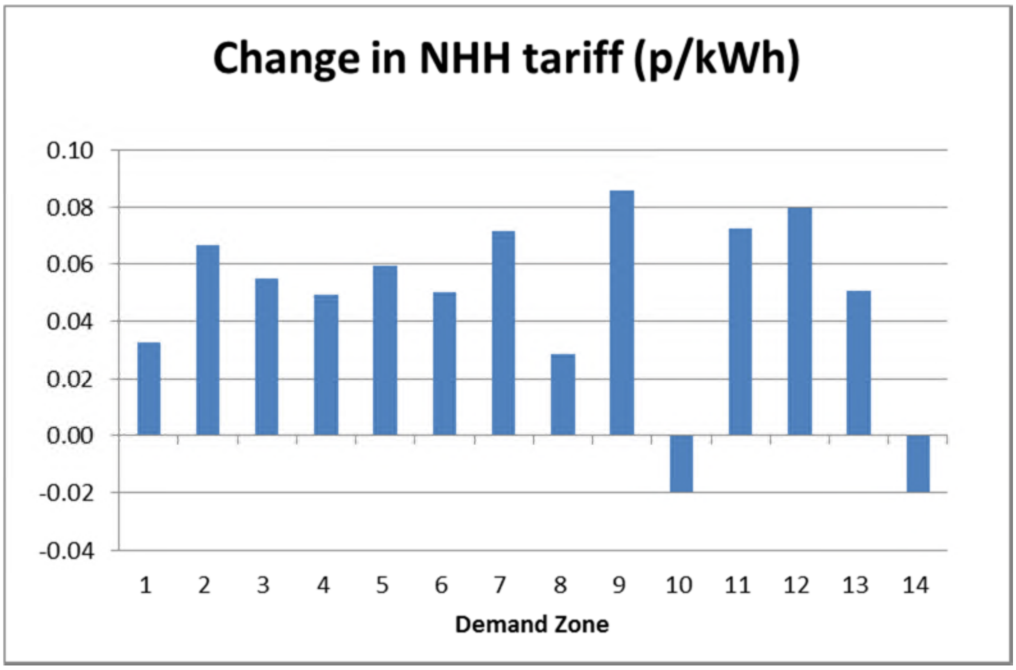
Table 14 and Figure 3 show the difference in the Non-Half-Hourly (NHH) demand tariffs between this and the October forecasts.

On average the NHH tariff has increased by 0.06p/kWh since the October forecast.

Table 14

Zone	Zone Name	Tariffs 15/16 (p/kWh)	Change from 14/15 tariff (p/kWh)	Change October-December forecast (p/kWh)
1	Northern Scotland	3.25	1.06	0.03
2	Southern Scotland	3.43	0.48	0.07
3	Northern	4.16	0.49	0.05
4	North West	4.74	0.50	0.05
5	Yorkshire	5.05	0.93	0.06
6	N Wales & Mersey	5.52	1.33	0.05
7	East Midlands	5.11	0.52	0.07
8	Midlands	5.35	0.61	0.03
9	Eastern	5.41	0.66	0.09
10	South Wales	5.11	0.84	-0.02
11	South East	5.68	0.51	0.07
12	London	5.89	0.75	0.08
13	Southern	5.96	0.58	0.05
14	South Western	5.68	0.44	-0.02

Figure 3 – Change in NHH Tariff



7 Sensitivities & Uncertainties

7.1 Transmission Revenues

Demand TNUoS charges are sensitive to changes in allowed revenue, i.e. an increase in allowed revenue will be reflected in the demand tariff residual.

Generation TNUoS charges are not sensitive to overall changes in allowed revenue because of the cap on average annual generation charges (described in Section 4.2.2) which fixes the revenue recovered by generators. However, generators tariffs are sensitive to changes in offshore revenues because any revenue recovered by offshore local tariffs displaces revenue recovered by the wider residual tariff, so an increase in offshore revenue reduces the wider generation TNUoS residual and vice versa. Approximately 75% of offshore revenue is recovered through the local TNUoS tariff.

7.1.1 Offshore

National Grid has forecast that Thanet, West of Duddon Sands and Gwynt Y Mor will asset transfer during 2014/15. If National Grid changes its forecast for these projects to 2015/16, when tariffs are finalised in January, then OFTO revenue for 2015/16 will be increased by the inclusion of the one-off Tender Cost Assessment fees. However, it may also decrease due to pro-rating the annual allowed revenues to reflect the proportion of the year that the new OFTOs are in place. Thanet has received Section 8 so is less likely to be delayed to 2015/16. Changes in forecast asset transfer date could give rise to changes of up to £13m.

National grid has forecast that Humber Gateway and Westermost Rough will asset transfer in 2015/16. Changes to the forecast transfer date when tariffs are finalised in January could give rise to changes of approximately +£9m/-£6m.

7.1.2 Effect on tariff residuals

The scenarios set out below are intended to illustrate the sensitivity of the forecast tariffs to changes in the revenue collected TNUoS tariffs. These scenarios do not represent a minimum and maximum tariff range. Note that the generation tariff is not sensitive to revenue changes following the EU limit on generation tariffs.

Table 15 shows the impact of a 1% change in revenues, upon generation and demand tariffs. Since this affects the residual tariff component the impact is the same in all zones.

Table 15 – Tariff Sensitivity to Revenue

Average Tariff Change for 1% change in revenue (+/- £26.55m)	15/16 Wider Tariff
Generation	+/- £0.00/kW
HH Demand	+/- £0.48/kW
NHH Demand	+/-0.06p/kWh

7.2 Demand charging base

An increase in the demand charging base decreases tariffs and vice versa. Table 16 shows the impact of a 500MW increase in the demand charging base. For simplicity this has been spread in proportion to the existing demand in each zone.

Table 16 – Tariff Sensitivity to Demand

Tariff change for 500MW increase in demand	Change to tariffs
HH Demand	-£0.34/kW
NHH Demand	-/+ <0.01 p/kWh

7.3 Generation charging base

The contracted background is now fixed (based on that at October 31st 2014) and so will not change before tariffs are finalised in January 2015. The contracted background is used to determine the locational tariff. The residual element of generation tariffs is dependent upon our forecast of chargeable 2015/16 generation and this may continue to be adjusted after this date up to when tariffs are finalised. The difference between contracted and chargeable is late notice closures and schemes that are delayed to future years.

An increase in the generation charging base decreases tariffs and vice versa. Table 17 shows the impact of a 1GW increase / decrease in the generation charging base. For simplicity this has been spread in proportion to the existing generation in each zone.

Table 17 – Tariff Sensitivity to Generation

Tariff change for +/- 1GW generation change	Change to tariffs
Generation Tariff	-/+ £0.12/kW

8 Tools and Supporting Information

8.1 Further Information

We are keen to ensure that customers understand the current charging arrangements and the reasons why tariffs change from year to year. If you have specific queries on this forecast please contact Mary or Stuart using the details below. Feedback on the content and format of this forecast is also welcome. We are particularly interested to hear how accessible you find the report and if it provides the right level of detail.

8.2 Charging forums

We will be hosting a webinar on December 19th to present the material in this forecast and answer questions in an open forum. Please contact us if you wish to participate so that we may send you details. In addition we will be discussing this report at the Transmission Charging Methodology Forum on 14 January.

8.3 Charging models

We can provide a copy of our charging model to allow you to conduct sensitivity analysis on our assumptions and scenarios. The model will be based on the contracted TEC background which has been used to calculate the locational tariffs in this update.

If you would like a copy of the model to be emailed to you, together with a user guide, please contact us using the details below. Please note that, while the model is available free of charge, it is provided under licence to restrict, among other things, its distribution and commercial use.

8.4 Numerical data

All tables in this document can also be downloaded as an Excel spreadsheet from our website:

http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

8.5 Contact Details

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9 Appendices

Appendix A	Contracted Generation changes for 2015/16
Appendix B	Transmission Owner Revenues
Appendix C	Generation Zones
Appendix D	Demand Zones

Appendix A: Contracted Generation changes for 2015/16

Table 18 provides details of contracted TEC changes notified since the October forecast but prior to October 31st.

Table 18 – TEC Changes

Station Name	Node	Revised TEC	Change
Andershaw Wind Power	LINM1Q	0	-35
Arecleoch	AREC10	114	-6
Carrington	CARR40	910	910
Kilgallioch	KILG20	0	-274
Mark Hill	MAHI20	53	-3
Race Bank	WALP40_	0	-500

Appendix B: Transmission Owner Revenues

The following tables show revenues for charging years 2013/14 to 2015/16. Actuals are shown for 2013/14 and tariff setting forecasts are shown for 2014/15 and 2015/16.

All reasonable care has been taken in the preparation of these tables and the data therein. However, the forecasts are subject to change, especially where they are influenced by external stakeholders, and actual revenues may vary from those shown.

These tables are offered without prejudice and National Grid and other Transmission Owners do not accept or assume responsibility for the use of this information by any person and cannot be held responsible for any loss that might be attributed to the use of this data.

All monies are nominal 'money of the day' unless stated otherwise and are presented to the nearest hundred thousand pounds.

Greyed out cells are either calculated or not applicable in the year concerned due to the way the licence formula are constructed. Hatched areas are due to limitations in available data. Inflation and base rate forecasts have been derived by National Grid and are consistent across Onshore TOs.

Opening Base Revenue allowances reflect the figures authorised by Ofgem in the RIIO-ET1 Final Proposals.

National Grid collects Network Innovation Competition Funding on behalf of all Transmission Owners receiving payments. Network Innovation Competition Funding is therefore only shown on the National Grid table.

This forecast contains as much information as can be currently made available whilst protecting commercially sensitive information and observing market disclosure considerations. In some cases estimates have been used where information is not yet publically available. These estimates are intended to remove excessive bias from the forecast tariffs so that the final outcome is as likely to be higher as it is to be lower.

National Grid Revenue Forecast

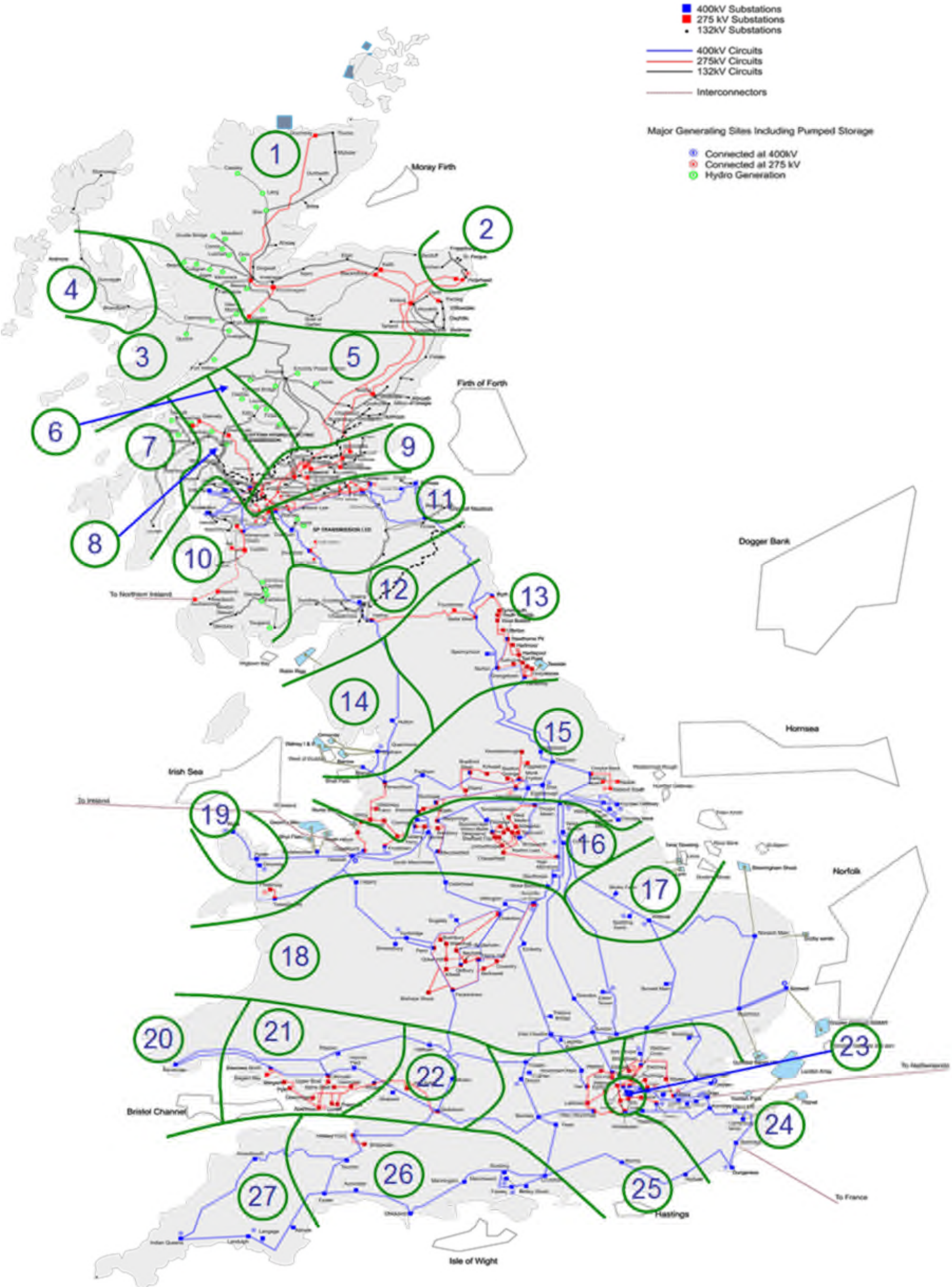
Description		Licence	Special	Applicable	Yr t-1	Yr t	Yr t+1	Notes
				Updated:		03/12/2014		
Regulatory Year					2013/14	2014/15	2015/16	
Actual RPI					251.73			April to March average
RPI Actual		RPIAt	3A		1.1667			Office of National Statistics
Assumed Interest Rate		It	3A		0.50%	0.50%	0.70%	Bank of England Base Rate
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	3A	ALL	1,342.3	1,443.8	1,475.6	From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	3A	ALL		-5.5	-114.4	Determined by Ofgem/Licensee forecast
RPI True Up	A3	TRUt	3A	ALL		-0.5	4.7	Licensee Actual/Forecast
Prior Calendar Year RPI Forecast		GRPIFc-1	3A	ALL	3.1%	3.1%	2.5%	HM Treasury Forecast then 3.0%
Current Calendar Year RPI Forecast		GRPIFc	3A	ALL	2.7%	3.1%	2.4%	HM Treasury Forecast then 3.0%
Next Calendar Year RPI forecast		GRPIFc+1	3A	ALL	2.5%	3.0%	3.2%	HM Treasury Forecast then 3.0%
RPI Forecast	A4	RPIFt	3A	ALL	1.1630	1.2051	1.2266	Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**1561.1**	**1732.7**	**1675.4**	
Pass-Through Business Rates	B1	RBt	3B	ALL			1.2	Licensee Actual/Forecast
Temporary Physical Disconnection	B2	TPDt	3B	ALL		0.1	0.0	Licensee Actual/Forecast
Licence Fee	B3	LFt	3B	NG			2.0	Licensee Actual/Forecast
Inter TSO Compensation	B4	ITCt	3B	NG			3.8	Licensee Actual/Forecast
Termination of Bilateral Connection Agreements	B5	TERMt	3B	NG	2.6	0.0	0.0	Does not affect TNUoS
SP Transmission Pass-Through	B6	TSPt	3B	NG	271.3	312.2	299.4	13/14 actual. 14/15 Charge setting. Later from TSP Tab
SHE Transmission Pass-Through	B7	TSHt	3B	NG	172.5	214.0	351.9	13/14 actual. 14/15 Charge setting. Later from TSH Tab
Offshore Transmission Pass-Through	B8	TOFTOt	3B	NG	105.4	218.4	249.8	13/14 actual. 14/15 Charge setting. Later from OFTO Tab
Embedded Offshore Pass-Through	B9	OFETt	3B	NG	0.6	0.4	0.7	Licensee Actual/Forecast
Pass-Through Items [B=B1+B2+B3+B4+B5+B6+B7+B8+B9]	**B**	**PTt**	**3B**	**ALL**	**552.3**	**745.1**	**908.9**	
Reliability Incentive Adjustment	C1	RIt	3C	ALL	12.4		2.4	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL			8.7	Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3E	ALL			2.8	Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt	3F	ALL			0.0	Only includes EDR awarded to licensee to date
Outputs Incentive Revenue [C=C1+C2+C3+C4]	**C**	**OIPt**	**3A**	**ALL**	**12.4**	**0.0**	**13.9**	
Network Innovation Allowance	D	NIAt	3H	ALL	6.1	10.9	10.6	Licensee Actual/Forecast/Budget
Network Innovation Competition	E	NICFt	3I	NG	0.0	17.8	18.8	Sum of NICF awards determined by Ofgem/Forecast by National Grid
Future Environmental Discretionary Rewards	F	EDRt	3F	ALL	0.0		0.0	Sum of future EDR awards forecast by National Grid
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	16.0	16.0	15.7	Licensee Actual/Forecast
Scottish Site Specific Adjustment	H	DISt	3A	NG	-1.6	2.0	2.3	Licensee Actual/Forecast
Scottish Terminations Adjustment	I	TSt	3A	NG	-0.4	-0.3	1.1	Licensee Actual/Forecast
Correction Factor	K	-Kt	3A	ALL	-2.7		56.4	Calculated by Licensee
Maximum Revenue [M= A+B+C+D+E+F+G+H+I+K]	**M**	**TOt**		**ALL**	**2143.2**	**2524.3**	**2703.0**	
Termination Charges	B5			NG	2.6	0.0	0.0	
Pre-vesting connection charges	P			ALL	43.3	47.0	48.3	Licensee Actual/Forecast
TNUoS Collected Revenue [T=M-B5-P]	**T**			**NG**	**2097.4**	**2477.3**	**2654.7**	
Final Collected Revenue	U	TNRt		ALL	2089.6	2484.5		Licensee Actual/Forecast
Over / (Under) Recovery [V=U-M]	V			ALL	-53.7	-39.8		
Forecast percentage change to Maximum Revenue M				**NG**		**17.8%**	**7.1%**	
Forecast percentage change to TNUoS Collected Revenue T				**NG**		**18.1%**	**7.2%**	

Scottish Power Transmission Revenue Forecast				Updated:	31/10/2014			
Description		**Licence Term**	**Special Condition**	**Applicable to**	**Yr t-1**	**Yr t**	**Yr t+1**	
Regulatory Year					**2013/14**	**2014/15**	**2015/16**	**Notes**
Actual RPI					251.73			April to March average
RPI Actual		RPIAt			1.1667			Office of National Statistics
Assumed Interest Rate		It			0.50%	0.50%	0.70%	As forecast by National Grid
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	3A	ALL	225.1	237.0		From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	3A	ALL		6.2		Determined by Ofgem/Licensee forecast
RPI True Up	A3	TRUt	3A	ALL		-0.1		Licensee Actual/Forecast
RPI Forecast	A4	RPIFt	3A	ALL	1.1630	1.2051		National Grid forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**261.8**	**292.9**		
Pass-Through Business Rates	B1	RBt	3B	ALL				Licensee Actual/Forecast
Temporary Physical Disconnection	B2	TPDt	3B	ALL		0.0		Licensee Actual/Forecast
Pass-Through Items [B=B1+B2]	**B**	**PTt**	**3B**	**ALL**	**0.0**	**0.0**		
Reliability Incentive Adjustment	C1	RIt	3C	ALL	0.5		-	Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL				Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3E	ALL				Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt	3F	ALL				Only includes EDR awarded to licensee to date
Financial Incentive for Timely Connections Output	C5	-CONADJt	3G	SP, SHE				Licensee Actual/Forecast/Budget
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	**C**	**OIPt**	**3A**	**ALL**	**0.5**	**0.0**		
Network Innovation Allowance	D	NIAt	3H	ALL	0.6	1.0		Licensee Actual/Forecast/Budget
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	25.5	29.2		Licensee Actual/Forecast
Correction Factor	K	-Kt	3A	ALL	-0.8			Calculated by Licensee
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**		**ALL**	**287.6**	**323.1**	**310.5**	
Excluded Services	P	EXCt		SP, SHE	7.0	7.7	8.4	Post BETTA Connection Charges
Site Specifc Charges	S	EXSt		SP, SHE	15.0	18.5	19.5	Pre & Post BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSPt**		**NG**	**279.6**	**312.3**	**299.4**	General System Charge
Final Collected Revenue	U	TNRt		ALL	271.3	312.2	0.0	Licensee Actual/Forecast
Over / (Under) Recovery [V=U-M]	V			ALL	-8.3	-0.1	0.0	
Forecast percentage change to TNUoS Collected Revenue T				**ALL**		**11.7%**	**-4.1%**	

SHE Transmission Revenue Forecast				Updated:	31/10/2014			
Description		Licence Term	Special Condition	Applicable to	Yr t-1	Yr t	Yr t+1	
Regulatory Year					2013/14	2014/15	2015/16	Notes
Actual RPI					251.73			April to March average
RPI Actual		RPIAt			1.1667			Office of National Statistics
Assumed Interest Rate		It			0.50%	0.50%	0.70%	As forecast by National Grid
Opening Base Revenue Allowance (2009/10 prices)	A1	PUt	3A	ALL	104.5	111.5		From Licence
Price Control Financial Model Iteration Adjustment	A2	MODt	3A	ALL		8.7		Determined by Ofgem/Licensee forecast
RPI True Up	A3	TRUt	3A	ALL		0.0		Licensee Actual/Forecast
RPI Forecast	A4	RPIFt	3A	ALL	1.1630	1.2051		Using HM Treasury Forecast
Base Revenue [A=(A1+A2+A3)*A4]	**A**	**BRt**	**3A**	**ALL**	**121.6**	**144.9**		
Pass-Through Business Rates	B1	RBt	3B	ALL		-10.7		RBt rebate anticipated in 2014/15
Temporary Physical Disconnection	B2	TPDt	3B	ALL		0.0		Licensee Actual/Forecast
Pass-Through Items [B=B1+B2]	**B**	**PTt**	**3B**	**ALL**	**0.0**	**-10.7**		
Reliability Incentive Adjustment	C1	RIt	3C	ALL	0.0			Licensee Actual/Forecast/Budget
Stakeholder Satisfaction Adjustment	C2	SSOt	3D	ALL				Licensee Actual/Forecast/Budget
Sulphur Hexafluoride (SF6) Gas Emissions Adjustment	C3	SFIt	3E	ALL				Licensee Actual/Forecast/Budget
Awarded Environmental Discretionary Rewards	C4	EDRt	3F	ALL				Only includes EDR awarded to licensee to date
Financial Incentive for Timely Connections Output	C5	-CONADJt	3G	SP, SHE				Licensee Actual/Forecast/Budget
Outputs Incentive Revenue [C=C1+C2+C3+C4+C5]	**C**	**OIPt**	**3A**	**ALL**	**0.0**	**0.0**		
Network Innovation Allowance	D	NIAt	3H	ALL	1.2	1.8		Licensee Actual/Forecast
Transmission Investment for Renewable Generation	G	TIRGt	3J	ALL	54.5	70.8		Excludes Asset Adjusting Events impacts
Compensatory Payments Adjustment	J	SHCPt	3C	SHE	0.0	0.0		Licensee Actual/Forecast/Budget
Correction Factor	K	-Kt	3A	ALL	-2.8			15/16 per 13/14; and 16/17 per RBt rebate in 14/15
Maximum Revenue (M= A+B+C+D+G+J+K]	**M**	**TOt**		**ALL**	**174.5**	**206.8**	**362.7**	
Excluded Services	P	EXCt		SP, SHE	0.0	0.0	3.5	Post BETTA Connection Charges
Site Specifc Charges	S	EXSt		SP, SHE	3.5	3.5	14.3	Pre & Post BETTA Connection Charges
TNUoS Collected Revenue (T=M+P-S)	**T**	**TSHt**		**NG**	**171.0**	**203.4**	**351.9**	General System Charge
Final Collected Revenue	U	TNRt		ALL	175.9	217.4	0.0	Licensee Actual/Forecast
Over / (Under) Recovery [V=U-M]	V			ALL	1.5	10.6	0.0	
Forecast percentage change to TNUoS Collected Revenue T				**ALL**		**18.9%**	**73.0%**	

Offshore Transmission Revenue Forecast			Updated:	03/12/2014			
Description	Licence Term	Special Condition	Applicable to	Yr t-1	Yr t	Yr t+1	
Regulatory Year				2013/14	2014/15	2015/16	Notes
Barrow				5.3	5.5	5.6	Current revenues plus indexation
Gunfleet				6.6	6.9	7.0	Current revenues plus indexation
Walney 1				12.1	12.5	12.8	Current revenues plus indexation
Robin Rigg				7.5	7.7	7.9	Current revenues plus indexation
Walney 2				12.6	12.9	13.3	Current revenues plus indexation
Sheringham Shoal				15.6	18.9	19.5	Current revenues plus indexation
Ormonde				11.2	11.6	11.9	Current revenues plus indexation
Greater Gabbard				11.4	26.0	26.7	Current revenues plus indexation
London Array				23.0	37.6	37.6	Current revenues plus indexation
2014/15 OFTOs					36.3	96.7	National Grid forecast of those expected to transfer in 2014/15
2015/16 OFTOs						10.9	National Grid forecast of those expected to transfer in 2015/16
Offshore Transmission Pass-Through (B8)	**TOFTOt**	**3B**	**NG**	**105.4**	**175.9**	**249.8**	

Appendix C: Generation Zones



Appendix D: Demand Zones